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West Virginia's Principles to Consider in Establishing Carbon Dioxide Emission Guidelines for Existing Power Plants

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I. Summary of Principles to Consider

Under the direction of President Obama, the U.S. Environmental Protection Agency (EPA) proposed standards in September 2013 that would limit carbon dioxide (CO_2) from new fossil-fueled power plants. The agency is using its authority under the Clean Air Act (CAA) Section 111(b) to set limits for new coal-fired plants, which would require at least partial carbon capture and sequestration (CCS). Standards for natural gas-fired plants would not require any level of CCS. Under its air permitting programs, EPA already regulates CO_2 as one of six greenhouse gases that may contribute to man-made global warming.

Concurrently, EPA also solicited input from a wide variety of stakeholders on how it should regulate CO_2 from existing power plants under CAA Section 111(d). The agency conducted "listening sessions" around the nation to hear ideas about potential regulatory considerations from states, industry, environmental groups and others. No coal states were chosen for session locations. EPA posed a number of questions but has expressly avoided taking any firm positions to date. The agency has acknowledged that the President's overarching 17 percent reduction goal of greenhouse gases from 2005 to 2020 should not be interpreted as applying directly to the power generation sector. Indeed, as explained herein, the chosen regulatory mechanism [CAA §111(d)] places significant constraints on EPA's authority; the factors which states must consider in developing implementation plans; and, ultimately, the level of emission reductions that can be legally and practically achieved.

The outcome of any regulatory requirements that reduce CO_2 emissions from existing coal-fired power plants will have profound, far-reaching effects on West Virginia and other states that depend heavily on coal production and coal-powered electricity generation. Put simply, if the wrong programs are put into place, the results could be devastating to the state economy and cascade West Virginia into a severe recession from which it may never recover. Other coal dependent states could be similarly impacted and the cumulative effect could significantly damage the national economy for many years.

West Virginia presents the following five principles for consideration in establishing CO_2 emission guidelines for existing power plants.

A. EPA should regulate CO_2 emissions from existing electric generating units (EGUs) under provisions for the protection of public welfare because CO_2 has not been demonstrated to have any direct adverse impact on public health. The agency should make a formal finding that *adverse effects on public health have not been demonstrated* as specified in 40 CFR §60.22(d)(1), and acknowledge that the provisions of 40 CFR §60.24(d) apply. This would provide maximum state flexibility in developing state CAA §111 plans.

B. EPA should establish mass-based emission guidelines in terms of reductions from a 2005 base year. The agency is required to consider the different sizes, types and classes of existing units, reflective of the level of emission control achievable through the application of the site-specific Best System of Emission Reduction (BSER) at all designated facilities. The guidelines should reflect the use of practical and cost-effective CO_2 control measures achievable within the fence-line.

C. EPA should establish CO_2 emission guidelines that allow maximum flexibility by states to meet emission reduction targets. Moreover, the agency must fully consider the wide range of variation among the existing power plant fleet and recognize that *states have broad discretion to balance the emission guidelines and compliance times against other factors of public concern in establishing emission standards, compliance schedules and variances.* For example, some states may want to credit GHG reductions realized through other policies and any other state mandated programs such as demand-side energy efficiency improvements.

D. EPA should extend the deadline for submission of state plans under CAA §111(d) to three years, so as to parallel the requirements for State Implementation Plans (SIPs) under CAA §110 and provide states adequate time for plan development. CAA §111(d) does not specify any specific time frame for plan submittal, and 40 CFR § 60.27(a) provides that *the Administrator may, whenever he deems necessary, extend the period for submission.* CAA §111(d) also does not specify any time frames or milestones to achieve any related state emission reductions. EPA must recognize that climate change is a long-term, multi-national problem that requires long-term solutions (measured in multiple decades) and there is no quick fix available. Compliance milestones should be extended accordingly.

E. EPA must allow states to *take into consideration, among other factors, the remaining useful life of the existing sources* when establishing performance standards, as required by CAA §111(d)(B).

The rationale for these principles is set forth below.

II. COAL, ELECTRICITY AND THE ECONOMY

A. Coal and Electricity Production

Coal-fired electricity generation accounted for more than one-third (37.4 percent) of the total electricity generated in the U.S. in 2012, more than any other source, and electricity production accounted for 91.5 percent of the U.S. coal consumption. Coal is projected to provide 39.4 percent of total U.S. electricity generation in 2013, 40.2 percent of the total in 2014, and is expected to remain the dominant source of electricity through 2040.[1]

As Senator Joe Manchin stated in his testimony before the Subcommittee on Energy and Power of the House Energy and Commerce Committee[2], on November 14, 2013:

> *We need a diverse energy portfolio – a true "all-of-the-above" mix of natural gas, nuclear, renewables, oil and coal. . . .*
> *Right now, coal provides 37 percent of all the electricity generated in the United States, and the Department of Energy projects coal will provide at least that much through 2040. Right now, we simply can't make up the difference with renewables. That's just wishful thinking.*
> *So, if we just standby and do nothing and let EPA eliminate coal from our energy mix, we're going to see the stability of our electrical grid threatened and see the price of electricity rise dramatically, jeopardizing America's economy and countless jobs with no real environmental benefit. . . .*
> *It's time the EPA started working as our partner, not our adversary, to achieve that balance. . . .*

B. Summary of Direct, Indirect and Induced Economic Impacts of the Coal Industry in West Virginia

In 2011, West Virginia was the largest coal producer east of the Mississippi River and second only to Wyoming in the U.S., accounting for nearly one-third of U.S. coal production east of the Mississippi River and 12 percent of total U.S. coal production. Coal-fired electric power plants accounted for 96 percent of West Virginia's net electricity generation in 2011, with renewable energy sources, primarily hydro and wind, contributing 3.3 percent. West Virginia is an exporter of energy – in 2010, 79 percent of the coal mined in West Virginia was shipped to other states, 90 percent of the coal consumed in West Virginia was used for electricity generation and 56 percent of the net electricity generated was consumed outside the state. West Virginia ranks second in the U.S. after Pennsylvania in net interstate electricity exports.[3]

In 2012, the CO_2 emissions from West Virginia's power plants were 19 percent lower than they were in 2005. These reductions can be attributed, in part, to the permanent shutdown, since 2005, of nine (9) coal-fired units, totaling 1,189 MW of lost generating capacity, predominately as a result of other environmental regulations. By 2015, as sources comply with the federal Mercury Air Toxics rule (MATS), an additional nine coal-fired units, totaling 1,630 MW of generating capacity, are scheduled to shutdown. These 18 units, totaling 2,819 MW, accounted for nearly one-fifth (18 percent) of West Virginia's generating capacity.

1. <u>Employment Impacts</u>[4]

With 63,896 employees, the combined employment impacts of the coal industry, associated transportation and power generation industries account for 11.3 percent of employment by private industry in West Virginia.

Employment Impacts of the Coal Industry in West Virginia			
	Direct	Indirect and Induced	Total
Coal Mining Industry Impact	22,570	27,468	50,038
Additional Impacts			
Rail Transportation	2,669	4,109	6,778
Water Transportation	374	614	988
WV Coal-Based Electricity Generation	1,900	4,192	6,092
Total	27,513	36,383	63,896

2. <u>Value Added Impacts</u>[5]

The value added economic impact of the coal industry represents the contribution to Gross State Product (GSP). At $6 billion, the combined direct impacts amount to nearly 9 percent of GSP. When including the multiplier effect of spending by these industries and households employed by the industry, the impact amounts to $8.8 billion or 12.7 percent of GSP.

Value Added Impacts of the Coal Industry in West Virginia **(million $ - 2012 basis)**			
	Direct	Indirect and Induced	Total
Coal Mining Industry Impact	$4,563	$2,175	$6,737
Additional Impacts			
Rail Transportation	$413	$271	$684
Water Transportation	$67	$40	$107
WV Coal-Based Electricity Generation	$945	$306	$1,251
Total	$5,987	$2,792	$8,779

3. Labor Income Impacts[6]

With combined labor income impacts of $3.9 billion the coal industry and associated transportation and power generation industries account for 17.5 percent of income paid by private industry.

Labor Income Impacts of the Coal Industry in West Virginia (million $ - 2012 basis)			
	Direct	Indirect and Induced	Total
Coal Mining Industry Impact	$1,913	$1,070	$2,983
Additional Impacts			
Rail Transportation	$243	$171	$414
Water Transportation	$30	$23	$54
WV Coal-Based Electricity Generation	$232	$179	$410
Total	$2,418	$1,443	$3,861

4. Tax Impact[7]

Taxes paid by the coal industry are estimated at $638 million in 2012. These include property taxes, severance taxes, workers' compensation, net income, and personal income taxes paid by industry employees and others.

Estimated Taxes Paid by the Coal Industry in West Virginia		
	2008	2012
Coal Mining Industry and Employees	$676 million	$638 million
Share of State Budget	17.5%	15.3%

III. FUNDAMENTAL EMISSION REDUCTION CONSIDERATIONS

A. Reduction of CO_2 Emissions from EGUs

The purpose of establishing regulations that govern the emissions of CO_2 from existing power plants is to reduce the amount of CO_2 emitted to the atmosphere, which in turn is expected to help slow climate change. EPA must bear the burden of proof that the reductions yield a significant net national benefit, while accounting for potential consequent global emissions increases. That is, some international emissions increases may occur in response to domestic actions, thereby diminishing some of the benefits of U.S. reductions. For example, if electricity prices adversely affect domestic primary aluminum production, other nations may increase production, thereby increasing their electricity demand and related emissions. There are two means of reducing CO_2 emissions from EGUs – improve energy efficiency or reduce the emission rate of CO_2.

1. Efficiency Improvement Options

There are two basic ways to reduce the generation of electricity from existing power plants – *supply-side* efficiency improvements or *demand-side* efficiency improvements. Supply-side efficiency improvements include site specific energy efficiency measures that improve heat rate (MMBtu/MW-hr) and therefore, lower CO_2 emissions at the plant. Conversely, demand-side electricity reductions are the result of efficiency improvements that result in the use of less electricity by the consumer – industrial, commercial or residential. These demand-side energy efficiency measures can include, among other things, the use of more efficient lighting, air conditioning systems, heating systems, or the installation of insulation, energy efficient windows or doors. Demand-side efficiency improvements may often be outside the control of the source and, therefore, may present limited applicability as control options.

2. CO_2 Emission Rate Reductions

There are two basic ways to reduce the emission rate of CO_2 from existing power plants – the addition of add-on, or post-combustion, controls or fuel switching to a lower emitting fuel.

Greenhouse gas emissions have not been regulated in the past, so existing power plants are not equipped with post-combustion CO_2 controls. CCS has not been adequately demonstrated at full scale on an existing power plant. There have been short term pilot tests, including one in West Virginia, where a small percentage (less than 2 percent) of the flue gas was diverted and a fraction of the CO_2 was captured and sequestered. However, this process has not been implemented on a commercial scale nor for extended periods. As EPA has verbally acknowledged, CCS is not a viable control option for existing sources. There are no adequately demonstrated add-on controls for CO_2.

Another option for reducing CO_2 emissions is switching to a fuel which emits less CO_2. Historically, EPA has not considered redefining the design of a source when considering available control options. Therefore, fuel switching generally cannot be considered an available control option.

3. Preferred Option

For existing power plants, BSER, the "best system of emission reduction which . . . has been *adequately demonstrated* for designated facilities" (emphasis added) cannot include CCS, fuel switching or demand-side electricity reductions. BSER must, therefore, strictly be limited to include energy efficiency measures inside the fence-line to achieve lower CO_2 emissions at the facility.

B. Regulatory Framework

The CAA invokes the principle of cooperative federalism – under which the federal and state governments are partners that share responsibility in the exercise of governmental authority. The CAA clearly delineates separate roles for EPA and the states. For example, under CAA §110, EPA sets the NAAQS and states develop SIPs to achieve and maintain the National Ambient Air Quality Standards (NAAQS). Under CAA §111(d), EPA establishes emission guidelines incorporating BSER, and states develop standards of performance that achieve emission reductions that meet the requirements of CAA §111(d).

1. Responsibilities under CAA Section 111(d)

EPA has formally posed the question, *How should EPA set the performance standards for state plans?*[8] The simple answer is: EPA should not set the performance standards for state plans. In fact, EPA is not authorized to do so, except when a state fails to submit a "satisfactory" plan.[9]

CAA §111(d) of the CAA does not authorize EPA to set *performance standards* for existing sources. That authority is instead conferred to the states. The section authorizes each state to develop a plan establishing performance standards for existing sources and directs EPA to provide, through regulation, a procedure for states to follow when developing and submitting those plans. The requirements parallel those which states follow to develop and submit SIPs to fulfill their obligations in achieving and maintaining the NAAQS under CAA §110.

2. 40 CFR Part 60, Subpart B

EPA established a procedure, similar to that provided under CAA §110, for the submittal and approval of state plans under CAA §111(d), which is set forth in 40 CFR Part 60, Subpart B. The first requirement that EPA set forth in its procedure was a requirement, or commitment, for itself. The agency commits to publishing a *draft guideline document containing information pertinent to control of the designated pollutant from designated facilities*.[10]

3. Emission Guidelines

EPA must: (a) in the guideline documents make a determination of whether CO_2 emissions from EGUs *may cause or contribute to endangerment of public welfare* and *whether or not adverse effects on public health have not been demonstrated;* (b) address subcategories of *different sizes, types, and classes of existing sources when costs of control, physical limitations, geographical location, or similar factors* warrant the application of differing guidelines; and, (c) set emission guidelines based on BSER which has been adequately demonstrated for existing facilities.

a. *Endangerment of Public Welfare or Public Health*

The first item that EPA must include in the draft guideline documents is information regarding whether CO_2 is causing or contributing only to endangerment of public welfare, or whether it also endangers public health. 40 CFR §60.22(d)(1) requires that if the EPA Administrator determines that CO_2 *may cause or contribute to endangerment of public welfare, but that* *<u>adverse effects on public health have not been demonstrated</u>*, *he will include the determination in the draft guideline document. . . .* (emphasis added). This is a critical finding. EPA's determination of whether or not there are demonstrated adverse health effects determines the degree of flexibility available to states in developing their 111(d) plans.

EPA's own Greenhouse Gas Endangerment Finding does not make a demonstration of direct adverse health effects. Instead, EPA relies on a series of conjectures that infer rises in ozone and $PM_{2.5}$ concentrations, as a result of increased heat waves and drought. However, ozone and $PM_{2.5}$ are criteria pollutants regulated through the establishment of NAAQS under CAA §110. These health-based standards must, by law, adequately protect human health, including that of sensitive populations. Therefore, it is inappropriate for EPA to consider further reductions in criteria pollutants as a justification for additional GHG regulation in this situation. EPA has not identified any GHG as a criteria pollutant nor has the agency established a related primary NAAQS which is associated with human health. Moreover, EPA has failed to make a direct correlation to specific concentrations of GHG, including CO_2, that would directly affect ground-level ozone or $PM_{2.5}$ concentrations. Otherwise, EPA would be compelled to consider these substances as pollutant precursors and regulate them under a NAAQS.

Because CO_2 emissions have not been demonstrated to directly cause adverse public health effects, EPA is forced to determine that *CO_2 may cause or contribute to endangerment of public welfare, but that adverse effects on public health have not been demonstrated*. This finding would allow the states to exercise maximum flexibility in developing suitable plans under 40 CFR §60.24(d) which provides that *States may balance the emission guidelines, compliance times, and other information provided in the applicable guideline document against other factors of public concern in establishing emission standards, compliance schedules, and variances*.

b. *Adequately Demonstrated Systems of Reduction, Degree of Emissions Reduction, Time for Design, Installation, and Startup of Systems of Reductions*

EPA is also committed to providing a description of the systems of emissions reductions that have been *adequately demonstrated*, the degree of emission reduction achievable from the various systems, and the time required for the design, installation and startup of the various systems.

c. *Emission Guidelines that Reflect the Best System of Emission Reduction (BSER)*

EPA is required to propose *an emission guideline that reflects the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated for designated facilities, and the time within which compliance with emission standards of equivalent stringency can be achieved*. EPA is also required to *specify different emission guidelines or compliance times or both for different sizes, types,* *and classes of the designated facilities when costs of control, physical limitations, geographical location, or similar factors make subcategorization appropriate*.[11]

The regulatory framework requires that EPA specify different emission guidelines and/or compliance times for different sizes, types and classes of existing facilities. The framework recognizes the diversity of the current fleet and provides the mechanism for the maintenance of the remaining generating infrastructure, the majority of which is comprised of fossil-fuel fired generation. EPA has a long history of not requiring the redefinition of a source when considering available control options.[12] EPA cannot require states to set performance standards based on changing the fundamental nature of the source or mandating a different mix of generating resources. In establishing the different emission guidelines, EPA should subcategorize by fuel-type and take into account a broad range of plant-specific factors, including the generating technology, size and age of the unit. The guidelines must recognize the need for the continued use of coal at coal-fired plants, oil at oil-fired plants, and gas at gas-fired plants, in order to preserve capacity and maintain grid reliability.

The nation's existing electric generating fleet is undergoing rapid and significant change due to increased environmental requirements and a dynamic energy market. These changes are expected to accelerate over the next few years as a significant number of coal-fired units are retired and new generation comes on line to replace lost capacity. Much of the new generation is expected to be natural gas-fired combined cycle (NGCC) combustion turbines and to a lesser extent, renewables, such as wind and solar. The national CO_2 emission rate for EGUs has been decreasing, with the national 2012 CO_2 emission rate 11 percent lower than the 2005 rate, while EGU CO_2 emissions have decreased 13 percent over the same time period. This decrease is a result of the shutdown of existing coal-fired units, the addition and increased utilization of NGCC units, the building of renewable generation sources, the building of new efficient coal-fired units, efficiency improvements at existing fossil-fuel fired units and energy efficiency improvements at the industrial, commercial and residential level.

An additional concern is the potential stranding of costs (those which the company is unable to recoup because of changes in regulations) incurred to satisfy other environmental regulatory requirements. In the last few years, many plants have invested billions of dollars for nitrogen oxides (NO_x) and sulfur dioxide (SO_2) controls to meet the regulatory requirements of the NO_x SIP Call and the federal Clean Air Interstate Rule (CAIR). EPA must consider all of the regulatory programs that already apply to power plants. The agency cannot ignore the complex, inter-related, and sometimes inconsistent regulatory requirements. Power plants have also addressed control retrofits to meet visibility goals (Best Available Retrofit Technology - BART) and SIP requirements established as part of plans to comply with more stringent Ozone and $PM_{2.5}$ NAAQS. In addition, plants are currently working to meet the air toxics requirements of the MATS rule. In West Virginia, all the coal-fired units that are not equipped with advanced SO_2 controls [Flue Gas Desulfurization (FGD)] and high efficiency NO_x controls [Selective Catalytic Reduction (SCR) or Selective Non-Catalytic Reduction (SNCR)] are either permanently shutdown or scheduled to permanently shutdown by the 2015 MATS compliance deadline. EPA must recognize that existing power plants which meet CAIR, BART and MATS have remaining useful life, and cannot be forced to shut down as a result of CO_2 emission guidelines under CAA §111(d).

States must be allowed to take into account the substantial CO_2 emissions reductions that have occurred since 2005 (i.e., the shutdown of nine (9) coal-fired units in West Virginia), and those which are scheduled to occur by 2015 (i.e., the shutdown of an additional nine (9) coal-fired units in West Virginia).

When establishing emission guidelines, EPA must balance the need for the control of criteria pollutants, which have scientifically demonstrated adverse public health effects, with the need for control of CO_2, which has not been demonstrated to have adverse effects on public health. The agency must recognize that some criteria pollutant controls may result in higher CO_2 emissions.

EPA must base the emission guidelines on CO_2 control measures that can be applied within the fence-line of existing plants, taking into consideration *costs of control, physical limitations, geographical location, or similar factors and remaining useful life*. The basis of the emission guidelines should be *inside the fence-line* efficiency improvements over which companies have primary control. Demand-side reductions from *outside the fence-line*, over which companies have little or no control, should not be used to set the emission guidelines. Establishing emission guidelines based on demand-side reductions does not allow sources certainty in their compliance options, nor does it allow states certainty in establishing standards of performance. Further complicating the issue is the problem of quantifying demand-side reductions occurring in other states where the electricity generated would have been used.

EPA, in the preamble to the proposed *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*, discussed the alternatives that were considered in the BSER analysis for new fossil-fuel fired stationary combustion turbines, which included modern, efficient NGCC units and modern, efficient NGCC units with CCS. EPA also discussed the alternatives that were considered in the BSER analysis for new fossil-fuel fired utility boilers and IGCC units, which included highly efficient new generation that does not include CCS technology, highly efficient new generation with *full capture* CCS and highly efficient new generation with *partial capture* CCS.

In the preamble, EPA stated . . . *NGCC with CCS is not a configuration that is being built today. The EPA considered whether NGCC with CCS could be identified as the BSER adequately demonstrated for new stationary combustion turbines, and we decided that it could not. At this time, CCS has not been implemented for NGCC units, and we believe there is insufficient information to make a determination regarding the technical feasibility of implementing CCS at these types of units*.

This same logic applies to the consideration of CCS at existing fossil-fuel fired utility boilers. A utility boiler equipped with CCS is not a configuration currently in use on existing utility boilers, and as such can not be considered as a candidate for BSER.

The Best System of Emissions Reduction, upon which EPA bases the emission guidelines,

a. should not mandate fuel switching;
b. should not require the shutdown of plants equipped with FGD and SCR/SNCR;
c. should not be based on reductions “outside the fence” over which companies have limited control; and,
d. should not include CCS.

The emission guidelines should be based on the application of BSER which has been adequately demonstrated, taking into account the different sizes, types and classes of existing sources, as well as costs of control, physical limitations, geographical location and similar factors which make sub-categorization appropriate.

4. State Flexibility

Because there have been no demonstrated adverse health effects directly attributed to CO_2, the Clean Air Act provides states great flexibility and discretion when developing state 111(d) plans. Under the concept of cooperative federalism, CAA §111(d)(1) requires states to *submit . . .a plan . . . which establishes standards of performance for any existing source* and directs EPA to *permit the State in applying a standard of performance to any particular source . . . to take into consideration, among other things, the remaining useful life of the existing source to which such standard applies.*

CAA §111(d)(2) gives EPA the authority to determine if a plan is *satisfactory*, however, the definition of *performance standard* and the direction to consider *among other factors, the remaining useful life* provide criteria for EPA to use in their determination of whether or not a plan is *satisfactory*. The CAA provides states substantial discretion in the development of a plan which establishes standards of performance for existing sources.

In recognizing the flexibility available to the states, EPA made a clear distinction between pollutants which pose a direct threat to human health as opposed to those that pose a threat to human welfare, but for which adverse public health effects have not been demonstrated. Much greater latitude is provided to the states when a pollutant has not been demonstrated to have adverse public health effects, since the provisions of 40 CFR §60.24(d) apply, which provides that *States may balance the emissions guidelines, compliance times, and other information provided in the applicable guideline document against other factors of public concern in establishing emission standards, compliance schedules, and variances*. Therefore, it is mandatory that EPA make such finding clear in the guideline documents. This finding would allow the states to exercise maximum flexibility in developing suitable plans.

C. Form of the Emission Guidelines: Mass-Based or Rate-Based

A *mass-based* emission standard establishes a quantity or mass of pollutant to be reduced from a baseline level. Mass standards are often expressed as a percent reduction in the mass of the pollutant from the baseline, which can be equated to specific number of tons, or an emissions cap (tons/year). In contrast, an emission *rate-based* standard is one in which the emission level is established in terms of the pollutant emissions per unit of heat input (lb CO_2/MMBtu) or per unit of electric production output (lb CO_2/MW-hr).

EPA insists it has no preconceived notions regarding how to implement a CO_2 reduction program for existing EGUs, and has conducted "listening sessions" around the nation to hear ideas about potential considerations from states, industry, environmental groups and others. Some states, environmental groups and industry groups have already weighed in with considerations and proposals for EPA.

1. Mass-Based Standard

One such proposal focused on a mass-based standard[13]. This approach establishes a baseline, and specific reduction targets for future years. A statewide baseline would be established using the CO_2 emissions from fossil-fuel fired EGUs in 2005, and reduction targets would be set for 2020 (17 percent reduction), 2025 (28 percent reduction) and 2030 (38 percent reduction). This mass-based approach would allow credit for the shutdowns, and efficiency improvements that have been made at facilities since 2005.

A significant fault with this proposal, no matter how well intentioned, is that it ignores the constraints which define BSER under CAA §111(d), by setting target reductions based on the President's Climate Action Plan, rather than the application of BSER as dictated by the CAA.

2. Rate-Based Standard

Another proposal focused on a rate-based standard[14], with emission levels from NGCC units serving as the target for fossil-fuel fired boilers. The CO_2 emissions from a NGCC unit are typically about half of those from a coal-fired boiler. The proposal would cut EGU CO_2 emissions by 26 percent (relative to 2005 emissions) by 2020 and 34 percent by 2025. These reductions would be achieved by setting state-specific emission rates based on the baseline share of coal and gas generation. EPA would set a target emission rate for each state for 2020, based on the state's baseline share of coal and gas generation. The state standards for 2020 would be calculated by applying a rate of 1500 lbs of CO_2/MW-hr for the baseline coal generation share and 1000 lbs of CO_2/MW-hr for the baseline gas-fired generation share. The allowable emission rate would drop further in 2025, with the rate applied to calculate the state allowable emission rate dropping for coal-fired generation from 1500 to 1200 lb CO_2/MW-hr, while the rate applied for natural gas-fired generation would remain at 1000 lb CO_2/MW-hr.

This rate-based approach would impermissibly force the retirement of a significant portion of West Virginia's coal-fired units, which currently provide 97 percent of West Virginia's electric generation. In order to comply with the rate-based proposal by 2020, West Virginia would have to replace 43.5 percent of its generation through fuel switching to lower CO_2 emitting fuels (that emit at the same rate as NGCC units), or replace 20.4 percent of its generation with renewables (zero-emitting sources), or some combination thereof. Such an approach is not realistic, nor is it feasible to assume that companies would be in a position to cost-effectively replace anywhere from 20 to 44 percent of their generation within less than 6 years. To put this in perspective, the required level of reduction would require the installation of 15 – 500 Megawatt (MW) NGCC units by 2020, or the installation of nearly 2,500 – 2 MW windmills, or some combination thereof.

3. Baseline

In the past, performance standards have been technology-based and tied to achieving the NAAQS for a particular pollutant. However, for CO_2 there is no NAAQS or readily-available control technology on which to base emission guidelines. EPA must distinctively define BSER for the multitude of existing EGUs. The level of control should be considered from a 2005 base year. The year 2005 is the appropriate base year for a number of reasons: it is the base year in the President's Climate Action Plan, it is representative of energy demand prior to the 2008-2009 recession, and 2005 has a robust emissions inventory because states were required to submit a full emissions inventory pursuant to the Air Emissions Reporting Requirements rule.

4. Preferred Approach

For the reasons described below, the best choice for the form of the emission guidelines is a mass-based approach that reflects the level of emission control achievable through the application of BSER at each and every designated (existing) facility in the state.

A primary concern of either approach is quantifying and verifying CO_2 emissions reductions. This is especially true if demand-side reductions are creditable. Compliance with an emission rate can allow for growth in production to exceed the reduction in rate, permitting higher mass emissions. In fact, there could be a point at which demand increases outpace the emission rate decreases, leading to net CO_2 emissions increases from the base year.

A mass-based approach achieves the desired level of reduction in a more equitable fashion by taking into consideration the differences among states and their existing energy portfolios. The mass-based approach maintains the integrity of the electricity grid, with a diverse fuel mix, which is vital to grid security and reliability. Compliance with an overall emissions cap ensures the desired reductions actually occurred. EPA's Clean Air Markets Division already requires that EGUs monitor and report CO_2 emissions as an integral part of other reporting mandates and could routinely track emissions just as they have done for other control programs such as CAIR.

West Virginia does not specifically support the levels of control proposed in either the rate-based or mass-based approach outlined above. However, we do support the use of a mass-based approach that is reflective of the level of emission control achievable through the application of BSER at all existing power plants.

D. State Performance Standards

States are given considerable latitude under CAA §111(d) in determining which approach to take when developing their plans and establishing standards of performance for existing sources. In accordance with 40 CFR §60.24(b)(1), "[e]mission standards shall either be based on an allowance system or prescribe allowable rates of emissions . . .[15]"

A mass-based allowance system would automatically account for improved efficiency at the plant level, reduced demand resulting from demand-side energy efficiency improvements, load shifting to lower CO_2 emitting generation, and the deployment of renewable (zero-emitting) energy sources. It appears that one of the most straight-forward approaches might parallel that of EPA's Acid Rain and CAIR trading programs. The federal agency could establish state CO_2 budgets, based on application of site-specific BSER. States could then allocate their budgets to their facilities using whatever methodology they choose (e.g. auction or historical activity). States would then have the option of allowing their sources to participate in an intrastate or interstate trading program.

Some have suggested demand-side energy efficiency programs, which reward the consumer beyond cost reductions in their utility bill by allowing them to generate credits that could be traded on the CO_2 market. While such a policy may have a lofty and admirable goal, such a course is not within the regulatory purview of many state environmental agencies when establishing standards of performance for existing EGUs. The same level of reduction can be achieved, with much less complexity, through the application of a supply-side (mass-based) trading program as outlined above. States and sources, by whatever means they determine as cost-effective, would still be free to encourage consumers to implement energy efficiency programs in their homes or businesses, thereby, reducing emissions though demand reduction.

E. Timing of Plan Submission

The regulation of CO_2 from the fleet of existing EGUs is a monumental endeavor. Therefore, EPA should provide states and the regulated community adequate time to consider, comment on and develop state plans. The requirement to submit a state plan within 12 months of issuance of the finalized guidelines does not provide adequate time for states to develop a viable plan, and complete the state adoption procedures. The rule making process in West Virginia can take from 12 to 18 months to complete, not including the time necessary for plan development.

CAA §111(d) does not specify any specific time line, and 40 CFR §60.27(a) states: *The Administrator may, whenever he determines necessary, extend the period for submission of any plan or plan revision or portion thereof*.

If EPA expects states to develop satisfactory plans, the agency must extend the deadline for the submission of state plans under CAA §111(d) to three years, so as to parallel the requirements for SIPs under CAA §110. Indeed, the plans of the former are likely to be much more difficult to develop than the latter.

IV. CONCLUSION

West Virginia is advocating that EPA follow CAA Section 111(d) requirements and the implementing regulations in 40 CFR Part 60, Subpart B, in establishing BSER. EPA should not start with a predetermined level of reduction and attempt to establish BSER to achieve that goal. Instead, the agency should establish the level of control achievable through the application of BSER from a bottom-up approach. That is the only legal mechanism to establish the level of reduction required. The President's stated goal of a 17 percent reduction in CO_2 emissions by 2020 has no bearing on the determination of BSER, nor in the application of BSER for determining the level of control achievable in the chosen regulatory approach.

It cannot be overemphasized that coal currently provides about 40 percent of U.S. electricity generation and is expected to remain the dominant source of electricity through 2040. Any new regulation of existing coal-fired power plants must provide for the cost-effective operation of these plants to ensure the continued reliability and stability of the power grid. Finally, the likely adverse economic impacts, including potential unintended consequences, must be carefully weighed against the uncertain environmental benefits of U.S. power plant CO_2 emissions regulations.

ENDNOTES

1. Data compiled from the following sources: U.S. Energy Information Administration (EIA), Electric Power Monthly, Table 1.1. Net Generation by Energy Source (http://www.eia.gov/electricity/monthly/index.cfm?src=Electricity-f2); Short Term Energy Outlook, November 2013 U.S. Electricity Generation by Fuel, All Sectors (http://www.eia.gov/forecasts/steo/report/electricity.cfm%20?src=Electricity-f3); Annual Energy Outlook 2013, Table 15. Coal Supply, Disposition and Prices, Reference Case (http://www.eia.gov/forecasts/aeo/source_coal.cfm); Annual Energy Outlook 2013, Coal's share of electric power generation falls over the projection period (http://www.eia.gov/forecasts/aeo/sector_electric_power_all.cfm#coalpowergen)

2. "Manchin Testifies at House Hearing in Support of Legislation to Rein in EPA's Proposed Standards." http://www.manchin.senate.gov/public/index.cfm/2013/11/manchin-testifies-at-house-hearing-in-support-of-legislation-to-rein-in-epa-s-proposed-standards

3. U.S. Energy Information Administration, West Virginia State Profile and Energy Estimates, Profile Overview. (http://www.eia.gov/state/?sid=WV)

4. Data provided by Christina Risch, Director for the Center for Business and Economic Research at Marshall University, in an email dated December 13, 2013, to Jeff Herholdt, Director of the West Virginia Department of Energy. Also supplemented by endnote 1 information.

5. Ibid.

6. Ibid.

7. Ibid.

8. U.S. EPA, "Considerations in the Design of a Program to Reduce Carbon Pollution from Existing Power Plants," September 23, 2013 version. http://www2.epa.gov/carbon-pollution-standards/questions-state-partners

9. CAA §111(d)(2)(A). http://www.law.cornell.edu/uscode/text/42/7411

10. 40 CFR §60.22(a). http://www.ecfr.gov/cgi-bin/text-idx?SID=16b3910c41ccb35488884bf87fa4246b&node=40:7.0.1.1.1.2.151.3&rgn=div8

11. 40 CFR §60.22(b)(5). http://www.ecfr.gov/cgi-bin/text-idx?SID=6fdcd546ff444bff5d23cca40c61562c&node=40:7.0.1.1.1.2.151.3&rgn=div8

12. U.S. EPA, *New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting*, Best Available Control Technology (BACT), October 1990, pg. B.13. http://www.epa.gov/NSR/publications.html

13. Commonwealth of Kentucky, Energy and Environment Cabinet – Principal authors: Kenya Stump, Division of Air Quality, Department for Environmental Protection; Aron Patrick, Department for Energy Development and Independence; Karen Wilson, Energy and Environment Cabinet; *Greenhouse Gas Policy Implications for Kentucky under Section 111(d) of the Clean Air Act, October 2013*. http://www.google.com/url?sa=t&rct=j&q=&esrc=s&frm=1&source=web&cd=1&ved=0CCsQFjAA&url=http%3A%2F%2Feec.ky.gov%2FDocuments%2FGHG%2520Policy%2520Report%2520with%2520Gina%2520McCarthy%2520letter.pdf&ei=ifacUtE5qdbJAcGwAQ&usg=AFQjCNE5E7lF1hMiSKQrMHrAGz2Vkzn5OA&bvm=bv.57155469,d.aWc

14. Daniel A. Lashof, et al., National Resource Defense Council, "Closing the Power Plant Carbon Pollution Loophole: Smart Ways the Clean Air Act Can Clean Up America's Biggest Climate Polluters," March 2013. http://www.nrdc.org/air/pollution-standards/default.asp

15. 40 CFR §60.24(b)(1) http://www.ecfr.gov/cgi-bin/text-idx?SID=27a49da687aec0ccb522a6bd84a80309&node=40:7.0.1.1.1.2.151.5&rgn=div8